Pacific Northwest NATIONAL LABORATORY

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Modeling Framework for Evaluating Grid Disturbances

December 2021

Sarmad Hanif
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U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
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Summary

Recent research by Pacific Northwest National Laboratory proposed parameter-based functional forms to quantify the impact of disturbances on electric power grids. This modeling was based on a concept of generalized grid disturbances that harmonized reliability and resilience. The focus of this report is proposing an evaluation modeling framework that utilizes a functional form approach. The report aims to guide planners/analysts to evaluate grid performance against disturbances, under a variety of existing and possible new mitigative actions. The functional-form approach identified three main stages—*avoid*, *react*, and *recover*—to quantify the impact of grid disturbances. To support practicality grid stages were proposed to be planned independently. For objectively quantifying the impact, a common performance metric (e.g., area under the curve of percentage customers online of the identified grid disturbance stages) over time was shown as an effective tool for such analysis.

The proposed evaluation modeling framework of this report builds on valuation principles of 1) creating a baseline of performance indicators (metrics) for business-as-usual conditions and 2) demonstrating the change in these metrics for alternate scenarios. The common metric for both existing and new mitigative actions provides an unequivocal valuation of the control actions. As new operation regimes (alternate scenarios) impact both the physical and control properties of the system, the evaluation framework proposes two main systems to be parameterized for accurately capturing dynamic response: 1) a physical subsystem and 2) a mitigative subsystem. The report also provides guidance on the selection of models from existing practices to guide system planners and analysts to help set up the evaluation models for grid disturbances. To further facilitate the evaluation setup, mapping of selected models to the current practices and tools from the industry is also presented.

To show case the usefulness of the proposed evaluation framework, we show a step-by-step procedure of evaluating a new mitigative strategy for dealing with grid disturbance, using TES as an example. First, we present a generalized TES model that consists of (1) formulating an objective and (2) deriving incentives from which (3) response is generated. We show how such components can be mapped against grid disturbance stages (avoid, react, and recover). Finally, we provided a qualitative comparison between a TES model and a conventional demand-response scheme.

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1.0 Introduction

Ramifications of recent blackouts testify that the safety and security of the electric power grid are necessary for the wellbeing of modern society (Smead 2021; Jelski 2021; Lee, Maron, and Mostafavi 2021). A functional-form model was proposed (Hanif, Chalishazar, and Hammerstrom 2020) to evaluate grid behavior under such grid disturbances as part of the Transactive Systems Program at Pacific Northwest National Laboratory. This section reviews the concept of grid disturbance modeling by first giving an overview of reliability and resilience, which were argued in the functional-form model work to warrant similar evaluations. Finally, a transactive energy system (TES) is discussed as a viable example mitigative system to handle grid disturbances.

The objective of this report is to demonstrate that grid disturbance modeling can be used for quantified assessment of existing and new mitigative strategies for grid disturbances. To this end, this report organizes relevant standard practices and tools that can be used to evaluate the impact of mitigation systems on grid disturbances. To illustrate the applicability of including new mitigative strategies, this report selects TESs and compares them against existing mitigative strategies to show the applicability of the grid disturbance mitigation assessment methodology.

1.1 Power System Reliability

Reliability is a measure of the ability of a system to perform its desired operations under the conditions for which it was designed to operate. Power system reliability is a measure of the ability to deliver electricity to all customers with acceptable standards (Billinton and Allan 1996). The qualitative definition of acceptable standards can be observed in the official definition of reliability by the North American Electricity Reliability Corporation (NERC 2007):

> "The North American Electricity Reliability Corporation (NERC) recognizes power grid reliability as an attribute of (1) the adequacy of the supply to meet energy demands for scheduled and reasonably unscheduled outages, and (2) withstanding sudden disturbances such as electric short circuits or unanticipated loss of system components."

Achieving the above-defined functionalities from a power system is the fundamental requirement of its reliability. Even though not mentioned explicitly in the existing literature, economics is interlinked with reliability. For example, an infinite transmission and distribution capacity of electricity along with extremely flexible consumption may yield an exceptionally reliable power grid, but what shall be the cost of constructing such a system? Therefore, economics is always one of the crucial factors to consider when striving to develop a reliable power system.

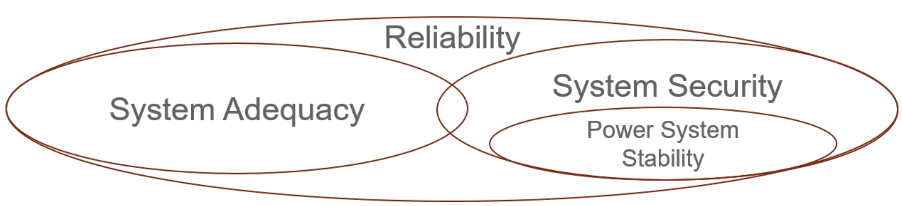

Figure 1. Modeling capabilities and compatibility of power system reliability component.

1.1.1 System Adequacy

Studies of system adequacy evaluate the capability of static system conditions and existing facilities to meet the system load. The analysis is based on steady-state conditions of the underlying components in the grid. System adequacy is considered the foundational block of reliability. To manage the calculation burden, system adequacy is performed by dividing the grid into its functional zones, as shown in Figure 2 (Billinton and Allan 1996). These functional zones are termed hierarchical levels (HLs) and contain features and functionality of their respective grid areas and components. We do not provide a discussion on the calculation methods for each HL, but present an important observation as follows. Distributing grid areas and developing models to represent them to evaluate the reliability of individual as well as aggregated components is a known practice among power systems engineers. This practice will be useful for developing an evaluation model for grid disturbances, which is the aim of this report.

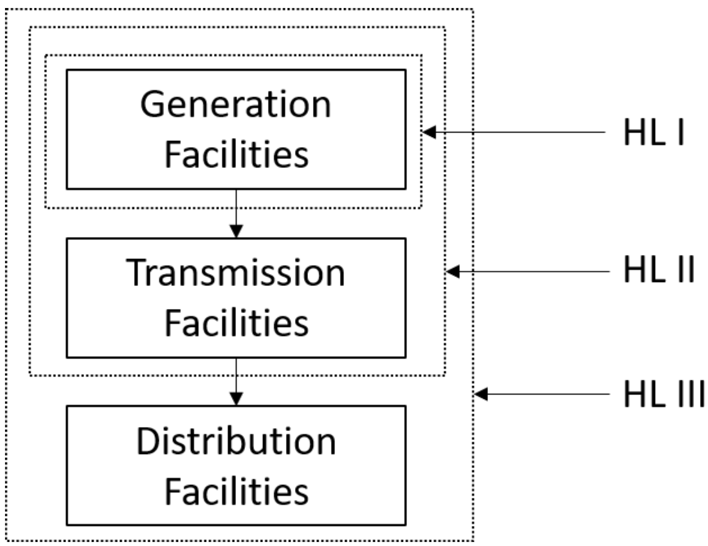

Figure 2. Classical functional zones for performing reliability system adequacy evaluation (Billinton and Allan 1996).

1.1.2 System Security

Studies of system security assess the dynamic and transient responses of the system to perturbations. The evaluation of system security involves dynamic modeling of individual and combined systems in the grid. System security is usually not well covered with respect to quantitative analysis in reliability literature. Consequently, system adequacy is a precursor for system security. In general, system security evaluates the reliability of the power system from the point of view of the dynamic nature of the grid. The dynamic nature of the power system is captured in power system stability studies, which include the dynamic responses of all system components. Three distinct phenomena are related to power system stability studies: rotor angle stability, frequency stability, and voltage stability.

1.2 Power System Resilience

Resilience measures how robust the grid is to external and internal threats. The U.S. Presidential Policy Directive 21 (PPD 21) defines resilience as "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions" (House

2013). In its definition of resilience, PPD 21 further clarifies that resilience includes a system's "ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents." There are other definitions for resilience too. For example, (Rieger 2014) uses five Rs—recon, resist, respond, recover, and restore—as the attributes to demonstrate the resilience of the grid.

There is no consensus regarding metrics for grid resilience quantification. For example, Table 1 shows a non-exhaustive list of some metrics used in literature for grid resilience. A comprehensive list of metrics can be found in (Petit et al. 2020). The common concept of the grid resilience metric is that they target "resilience events," which are defined as high-impact, low-probability events.

Table 1. Example list of resilience metrics.

Reference	Metrics
(Johnson et al. 2020)	Demand/energy not served.
(V. H. Chalishazar 2019)	Time and cost of recovery, load recovery factor, and lost revenue.
(Amirioun et al. 2019)	Vulnerability index, degradation index, microgrid resilience index.
(Panteli et al. 2017)	Four-stage procedure: Stages 1 and 2 evaluate how fast and how the load system degrades, and Stages 3 and 4 describe how extensive the degradation and recovery of the system are, respectively. The choice of system performance was left to the analyst.

The first issue with measuring resilience through "resilience events," which are infrequent severe events, is that there is no true baseline by which an entity can measure its improvement or slippage in system resilience. The second issue is that a system is deemed resilient by that which does not occur. This makes resilience only meaningful in a statistical sense.

1.3 Introduction to Grid Disturbance

As shown in Section 1.1, reliability is used to evaluate business-as-usual conditions and explicitly excludes major disturbances, whereas Section 1.2 demonstrates resilience to cater for major events. The concept of grid disturbance, as proposed in (Hanif, Chalishazar, and Hammerstrom 2020), harmonizes reliability and resilience such that it utilizes metrics from the reliability concepts as the baseline to be used to predict resilience for future major events in a statistical manner. The term "disturbance" is used from here on in this report to represent the likelihood of system degradation caused by business-as-usual (reliability) and severe events (resilience).

A grid's ability to handle a disturbance is modeled using its capability to:

1. Avoid a grid disturbance.
2. React during a disturbance to lessen the extent of system degradation.
3. Recover rapidly after a disturbance has occurred.

Figure 3 shows these three stages of grid disturbance.

Avoid: The avoid stage begins during the normal pre-contingency state and ends if and when the value of the performance measure degrades.

React: Upon failure of avoidance efforts, system degradation begins to occur, and the system enters the react stage. Measurable degradation of system performance defines the start of the react stage, which ends when the system performance cannot or ceases to degrade.

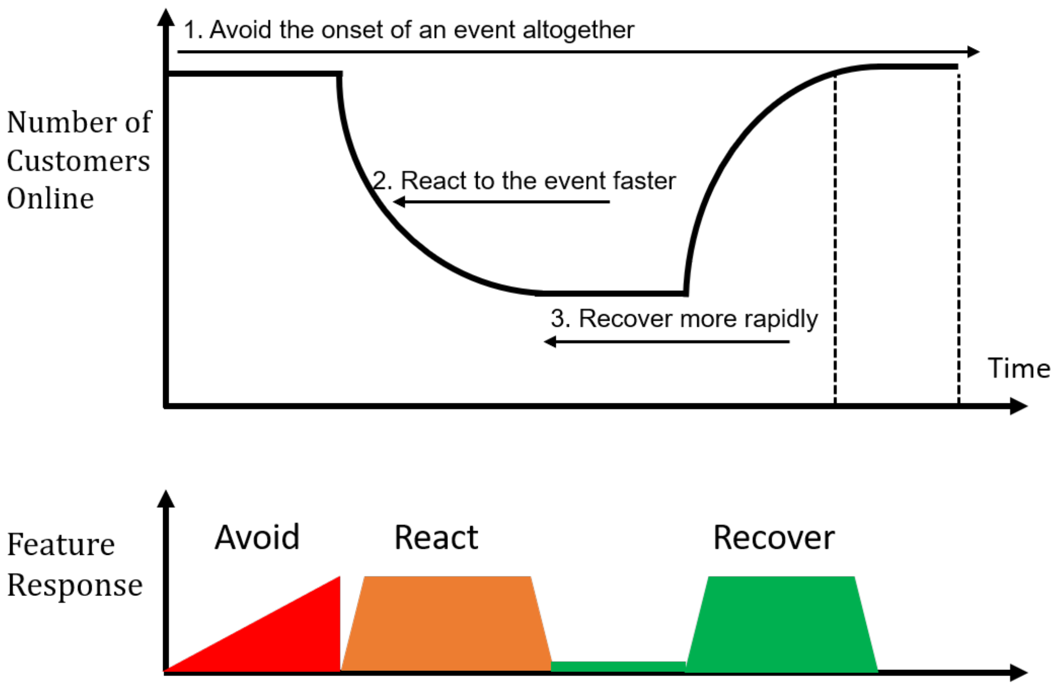

Figure 3. Typical grid disturbance system response and its features, with the number of customers online as an example grid performance measure (Hanif, Chalishazar, and Hammerstrom 2020).

Recover: At the end of the react stage, the system has degraded to its worst performance measure and the recover stage begins. The recover stage ends once the system performance is brought back to the nominal state.

Each stage of grid disturbance is mapped to a common metric, e.g., the number of customers online. For more information on the individual disturbance stages, interested readers are referred to (Hanif, Chalishazar, and Hammerstrom 2020).

1.4 Introduction to Transactive Energy System

One of the promises of smart grids is the vision of highly distributed operation of distributed energy resources (DERs). In TESs, economics and controls are coordinated in a market-based construct to manage DERs (Hammerstrom et al. 2016; Widergren et al. 2017). Because of their ability to introduce distributed intelligence in power systems, TESs have been widely discussed as a means of applying flexibility in grid operations (Kok and Widergren 2016). TES qualities are envisioned to help the grid mitigate disturbances (Hanif, Chalishazar, and Hammerstrom 2020). For example, in the case of transmission or distribution infrastructure loss, TES might help operate the rest of the grid with minimal outages and loss of power to customers. Similarly, with the possibility of infrastructure to coordinate DERs, especially battery systems, TES may help further minimize customer outages with limited additional generation source deployment.

1.5 Report Organization

The rest of this report is organized as follows: Section 2.0 presents concepts related to the generalization of physical and mitigative subsystems to be utilized for the grid disturbance evaluation model. Section 3.0 presents methods and tools that may be utilized in capturing the necessary dynamics and characteristics of the grid disturbance model. Section 4.0 presents TES modeling and examples as a new mitigative system, comparing the system against an existing mitigative strategy and examining its impacts on the grid disturbance model. Chapter 5.0 presents conclusions and future work, followed by a reference list. An appendix presents examples to support the discussions in Section 3.0.

2.0 Grid Disturbance Evaluation Model

Figure 4 shows the proposed methodology for evaluating existing and new mitigative strategies against grid disturbances. The proposed methodology is aimed at providing objective quantification of mitigative strategies for grid disturbance procedures. For an analyst tasked with assessing its grid's resilience against disturbances, the proposed methodology is to provide guidance in terms of teasing out parameters that may be deployed for developing a grid disturbance model. In addition, the parametric approach includes helping analyze whether new mitigation strategies, such as TES, yield any improvements with respect to existing mitigation strategies. The comprehensiveness of the methodology is attributed to the fact that systems are to be modeled for each grid disturbance stage of avoid, react, and recover. The practicality of the methodology is to be warranted by staging modeling efforts for each stage independently. The system first needs to be generalized in terms of its existing physical and mitigative subsystems. Such generalization not only involves identifying the current components, but also setting up the analysis such that it contains prediction of disturbance scenario(s) and its representation across desired temporal and spatial granularity. Analytical model(s), statistical outcomes, or a combination of both may be utilized to generalize these subsystems. Examples of the individual subsystems follow.

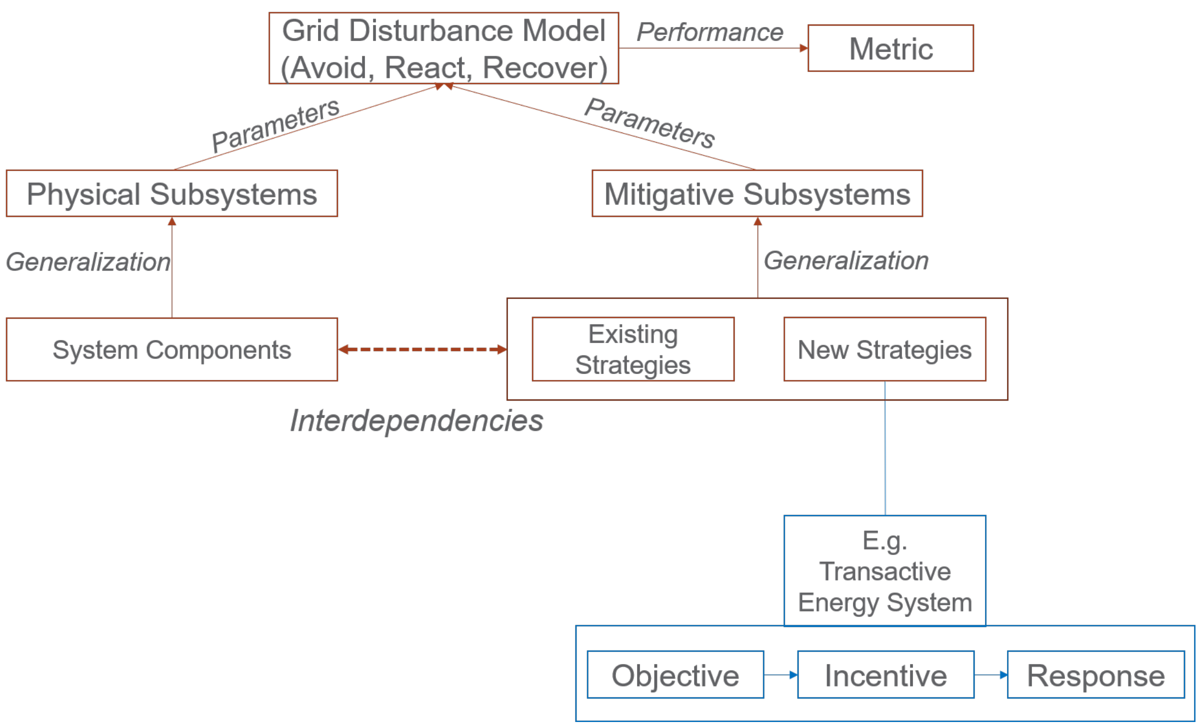

Figure 4. Methodology for evaluating grid disturbances in the presence of new and existing mitigative strategies.

Physical Subsystems: These represent parameters to be derived from the physical components of the grid. For example, parameters representing transmission lines, a generation fleet, and distribution grid capacities.

Mitigative Subsystems: These represent parameters that will be derived from in-place mitigation systems for rejecting disturbances. These correspond to strategies which are combination of controls and capabilities. For example, parameters representing generation protection setting, relay setpoints and voltage ride-through settings. Like existing mitigative systems, as new mitigative systems are proposed, their impact must also be captured using parametric approach. In such a way, grid performance to disturbance may be quantified and compared against various existing and new mitigative strategies.

Metric: The metric quantifies the performance of the grid against all disturbances and in all stages (avoid, react, and recover). Moreover, the metric harmonizes the concepts from reliability and resilience by (1) selecting a performance measure to show variation under any reliability and resilience event, and then (2) by calculating a metric common to all disturbance stages, such as an area under the curve.

It is important to note that there are interdependencies between the physical and mitigative systems. This is related to the course of actions associated with physical systems, which is how the parameters affecting each other can be identified and perhaps modeled. For example, a course of action to safeguard transmission lines (mitigative system parameter) ultimately rejects a disturbance and therefore keeps the transmission line capacity unchanged (physical system parameter).

To capture such interdependencies in power systems, there are models that represent both physics and mitigation systems in combination. Such models are usually packaged for various components of power grids and used for various studies. Examples include production cost models for analyzing capacity expansion options, electromagnetic/electromechanical models for observing system transients/dynamics, multi-phase steady-state power models for conducting distribution grid power-flow feasibility, and thermodynamical models to represent air temperature evolution of houses containing air-conditioning loads. Depending on the grid area under consideration and the scenario to be modeled, an analyst may find such models to be useful for teasing out physical and mitigative system parameters.

This report provides guidance for developing such models, depending on the grid disturbance stage in question, i.e., avoid, react, or recover. However, because grid performance is measured against all disturbance stages, each stage is critical to the analysis and therefore must be adequately represented by the chosen models. Models to tease out parameters for each stage are identified based on their internal requirements, which may differ from the models used for conventional power system analysis. Some examples are as follows. For the avoid stage, the proposed model selection is the spatial and temporal granularity requirements of the analysis. These requirements are then mapped to predicting the performance degradation onset, i.e., failure to avoid the disturbance scenario. For react and recover, because the disturbance is “local” in time, the proposed model selection becomes dependent on the disturbance trajectory modification due to mitigative systems. For example, for the react stage, an accurate grid disturbance trajectory involves how well the analyst can capture the initial degradation followed by mitigative degradation. In doing so, the report presents guidance on relevant model selection for all grid disturbance stages, which an analyst may rely on based on the desired accuracy, available data, and computational power.

2.1 Physical Subsystem

This section introduces important components of physical subsystems, the characteristics of which must be captured by the grid disturbance model. It is our hope that when the subsequent chapter on model selection for grid disturbance stages is presented, this section will have provided sufficient general guidance on including the necessary components of the physical subsystem. We do not intend to provide an exhaustive list of all physical subsystems existing in the grid. Three main sets of physical subsystems exist in the power grid: (1) generation, (2) transmission, and (3) distribution. Here, the type of generation considered is a large, centralized generator because small generators are usually connected at the distribution level. Recommendations for generalizing the three main components of the physical subsystem follow.

Generation Subsystem: For generation assets, useful categories under which to organize them are fuel type, technology type, and auxiliary equipment. Examples of fuel types include nuclear, gas, and coal. Based on the fuel type, the technology generating the power can also be listed, e.g., a Francis/Kaplan turbine for a hydroelectric plant. Finally, the auxiliary equipment required to provide controls to the generating technology must be accounted for, such as the field controller, the exciter for synchronous generator control, fault ride-through equipment, etc.

Transmission Subsystem: For transmission assets, a useful inventory would be grouping them under main transmission technology types and under relevant control equipment, e.g., overhead line and underground cables. Further classification between the technology types could be based on the voltage level information to help group transmission lines of same strength and purposes. Another category is the relevant control equipment needed for transmitting power, which includes transformers for changing voltage levels, line conditioners, etc.

Distribution Subsystem: For distribution assets, a similar organization as that used for transmission assets can be implemented for the conventional components. New components related to smart grids, such as DERs, may be organized using the generation asset inventory methods.

Based on the above inventory classification of the physical subsystem components, a suitable representation for each can be found for the grid disturbance stages of avoid, react, and recover. These representations can be a physical-based model, statistical-based availability model, or a combination of both. However, these models must be aligned with the mitigation subsystem responsible for changing operating strategies for the physical subsystem. To this end, generalization of a mitigative subsystem is presented next.

2.2 Mitigative Subsystem

The mitigation subsystem, as configured, in conjunction with the physical system and a host of other existing mitigations, will affect the model parameters in one way or another and thereby change the grid system's response to disturbances. An analyst must evaluate available mitigative strategies at their disposal before implementation. Similar to generalizing a physical subsystem, we provide components of mitigative subsystems that can be used to pinpoint mitigative actions and strategies and their impacts on physical subsystems.

2.2.1 Contingency Selection Process

First, we provide guidelines for the general use of contingency as a discrete course of action taken by a mitigative subsystem. A contingency is triggered by the mitigative system upon observing certain conditions, such as exceedance of thresholds or depletion of reserve margins. The effectiveness of mitigation strategies that an analyst evaluates should be compared against the impact of the unmitigated grid disturbance event on the system. The system response to any possible grid disturbance is a function of selected contingencies. For example, deployment of demand flexibility during peak hours is a type of contingency that can help alleviate system overloads and thus avoid grid disturbance due to tripping of components. Selection of such contingencies depends on the thresholds and margins of the physical subsystem. Note that although both the threshold and margins are related to each other, both must be identified as follows. Physical components have thresholds associated with them, from which their performance/failure can be estimated. To make sure that physical components' thresholds are not violated, they are operated within a certain margin to avoid their failure. In the following sections, we present examples of how a system/component threshold and its margins influence a grid operating engineer's selection of a suitable contingency for resilience enhancement.

2.2.1.1 Thresholds

A threshold is a mitigative subsystem component that may be crucial to identifying when a contingency will be triggered. In electric power grids, components are operated with predefined thresholds. These thresholds are dependent on the component type, life, and their exposure to any grid disturbance event (a line fault is proportional to its length). While it is challenging to measure these thresholds directly, a simulation-based approach or risk assessment methodology such as HAZUS (FEMA 2021), or any historical data if available, can be used to define the system/component threshold and map it to the event for estimating physical, economic, and social impacts.

Figure 5 shows an example of mapping such a threshold to an event onset using wind-fragility curves. In this case, the failure probability of a component for an event (wind speed) determines whether the component fails or not, i.e., if the threshold is crossed or not.

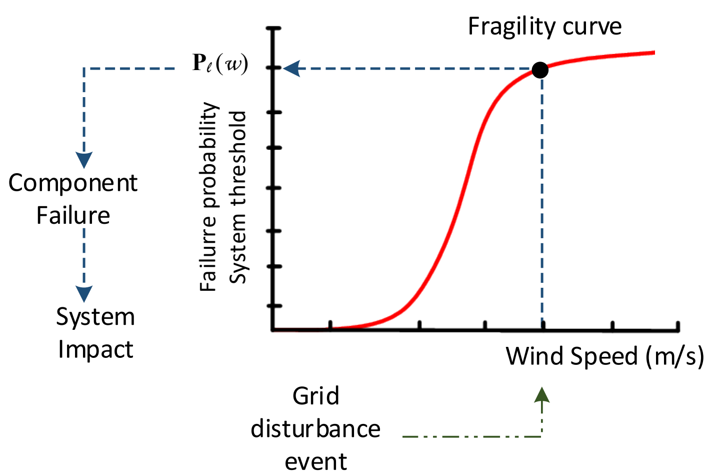

Figure 5. A fragility curve—mapping a system threshold to possible event onset.

A few examples of the interplay between thresholds and the relevant contingencies for minimizing the impact of a grid disturbance for different physical subsystems are as follows.

1. For a hydropower generation facility, a threshold can be defined for the reservoir level. A falling reservoir level due to rising temperatures and frequent droughts decreases the availability of hydropower generation. Therefore, it is important to define a threshold for the reservoir level and implement a suitable contingency (e.g., power transfer from different areas) to avoid any possible power outage.

2. A threshold for transmission lines against extreme events such as snow/ice storms or hurricanes can be defined based on line parameters such as length and expected sag. A proper contingency could be called upon beforehand or during the grid disturbance to avoid the failure of the line or to avoid outage with some reconfiguration.
3. A service transformer's threshold can be defined based on its kVA limit and total time of capacity violation. With these parameters in hand, a distribution engineer can implement a contingency action such as implementing a rolling blackout or triggering TES strategies to defer the loads and avoid tripping the service transformers.

2.2.1.2 Margins

Another important component of mitigative subsystems is the identification of system/component margins and their relationship to the selection of suitable contingency. For a grid disturbance event, it is also important to investigate how the margin and system threshold are related to the contingency selection because the combination of margins and system thresholds usually allows a system to operate normally, even though major disturbances have occurred (for example, N-1 criteria[1]). Such a criterion may help provide a security margin against unwanted conditions in the system. If a suitable contingency is selected based on the given margin, the system threshold may not be violated, and such an event will not map to an impact. However, if the system stability margin is compromised by a series of events, it is likely that the component will operate beyond the threshold for some predefined time and eventually fail. This is captured by the react stage in the grid disturbance theory, commonly referred to as the adaptive capacity of the system. This entails the degree to which the system is capable of self-organization and its ability to change endogenously.

A few examples of system margins that trigger a mitigative subsystem and relevant contingencies to minimize the impact of a grid disturbance for different physical subsystems are as follows.

1. If a hydropower generation facility is operating during the winter season, head is a measure of a margin and will be helpful in selecting mitigative actions, such as procurement of alternate generation (e.g., diesel genset).
2. A transmission line's ampacity and its historical loading levels provide a margin that allows the operator to decide on a remedial action scheme, such as adjusting or tripping generation, tripping the flexible load with a suitable TES mechanism, or reconfiguring a system and thus limiting the impact of cascading or extreme events.
3. With increased penetration of rooftop solar, low-voltage networks are operating near the overvoltage zones during peak generation. Persistent overvoltage can shorten a component's lifetime and increase the chance of equipment failure. A suitable TES mechanism could be adopted to motivate customers to install battery storage or a solar photo-voltaic curtailment scheme to provide a sufficient margin (V-1.05) and thus avoid the overvoltage phenomenon and possible grid disturbances with poor power quality.

[1] N-1 criteria is the criteria when a system is able to withstand at all times the loss of a single system component.

3.0 Model Selection for Grid Disturbances Evaluation

Section 2.0 presented a model for evaluating the impact of existing and new mitigations on grid disturbances. An overview of physical and mitigative subsystems was presented and options to generalize these systems were discussed. This section extends the discussion toward models that can be used to represent the behavior of physical and mitigative subsystems as well as their interdependencies. The goal of this section is to provide appropriate tools and methods to help obtain parameters for setting up the grid disturbance model. We do not present a discussion on parameters for the grid disturbance stage because they were already presented in (Hanif, Chalishazar, and Hammerstrom 2020).

3.1 Representing the Avoid Stage

For an analyst to identify a vulnerability, implement mitigative strategies, and make investment decisions such that their respective grid area is equipped to avoid disturbances, we disaggregate model choices across two dimensions: time and space.[1] One of the main goals of the avoid stage model is to capture relevant scenarios that may or may not trigger an event during an analysis period. The results from (Hanif, Chalishazar, and Hammerstrom 2020) provided three methods to capture these scenarios.

1. Likelihood of Scenarios for Events: These modeling techniques capture probabilistic scenarios of events. For example, this could include modeling a mitigative treatment that delays the outage and estimating the probability that a hurricane will damage the transmission and distribution assets.
2. Identify Stressor Thresholds: Apart from capturing the likelihood of an outage due to external events, identifying and modeling thresholds that may get violated due to various stresses acting on the system is also needed. There exist numerous such thresholds, which are indicators of the safe operation of the grid. Because these thresholds cater for stressors acting on the system, we call them stressor thresholds. For an example, to deal with various uncertainties in the grid, reserves are implemented. Based on historical data and the system condition, the utility may define a reserve threshold below which the event scenario is identified, triggering the appropriate mitigative strategy.
3. Relevant Grid Element Life Models: Finally, there is another possible outage scenario related to lifetime completion of vulnerable components. This may be captured by modeling the life degradation of vulnerable components. An example of this modeling type is representing the impact of distribution transformer life reduction due to overheating as it experiences overloading during peak load conditions.

<u>Time Dimensionality of the Scenario Onset Determination</u>: The following time dimension categories are selected:

- Low-Granularity Analysis Period: E.g., hourly to daily time resolutions
- High-Granularity Analysis Period: E.g., minutes to seconds time resolutions
- Short-Horizon Analysis Period: E.g., within a few hours
- Long-Horizon Analysis Period: E.g., day-ahead, and longer

[1] Note that similar dimensions (space and time) have been chosen to provide valuation of diverse methodologies (Hammerstrom et al. 2016).

Based on the combination of the above time dimensions, examples of avoid stage models to help capture the functional form for an analysis period are presented in Table 2.

Table 2. Avoid stage models generic examples across time dimensions.

Scenario Onset Modeling	Low-Granularity/Short-Horizon	Low-Granularity/ Long-Horizon	High-Granularity/ Short-Horizon	High-Granularity/ Long-Horizon
Probabilistic Scenarios Onset	• N/A	• Aggregated event models – fragility curves, etc.	• Analysis of seismic activities	• N/A
Stressor-initiated Scenarios Onset	• DC/AC power flow • Real-time copper plate feeder	• Long-term stability models • Long-term copper plate requirement analysis	• Voltage collapse analysis • Electromagnetic modeling • Electromechanical coupled modeling	• AC optimal power-flow model coupled with a first-order electro-mechanically coupled model
Functionally Tracked Scenario Onset	• Daily operation rules	• Long-term loss of life modeling of components	• Short-circuit analysis with Physical Device Model	• Multi-physics device models coupled with transient simulation

Spatial Dimensionality of the Scenario Onset Determination: The following space dimension categories were selected.

- High Aggregation of Analysis Area: Aggregation of the area to represent it as a single node.
- Low Aggregation of Analysis Area: Geographical variation in the area under analysis.
- Large Scale of Analysis Area: Multiple distribution system feeders to transmission nodes in the area.
- Small Scale of Analysis Area: A house to a feeder level area.

Based on the combination of the above space dimensions, examples of avoid stage models to help capture the functional form for an analysis period are presented in Table 3.

Table 3. Avoid stage models generic examples across space dimensions.

Scenario Onset Modeling	High Aggregation / Small Scale	Low Aggregation / Small Scale	High Aggregation / Large Scale	Low Aggregation / Large Scale
Probabilistic scenario onset	• Likelihood of generic house/small community damage modeling	• Locational probability of damage with GPS coordinates model	• Aggregate damage model of the feeder structures	• Likelihood of failure of detailed grid structure models

Scenario Onset Modeling	High Aggregation / Small Scale	Low Aggregation / Small Scale	High Aggregation / Large Scale	Low Aggregation / Large Scale
Stressor-initiated scenarios onset	• Generic load/ voltage monitoring/ estimation/ modeling	• Location specific load / voltage monitoring / estimation / modeling	• Aggregated reserves / voltages / availability / tie-line flow monitoring/ estimation/ modeling	• Nodal information for reserves / voltages/area control error monitoring / estimation / modeling
Functionally tracked scenario onset	• Simple fuse box/appliance loss of life models to represent failure of load being served	• Location dependent detailed fuse box/appliance loss of life models failure	• Major components (transformer / OLTC) failure model for the service area	• Detailed physical life degradation models for the entire service area

Based on guidance on model choices given in Table 2 and Table 3 and in Appendix A.1, we provide examples of tools and practices adopted by system operators, such as ISOs, that may serve as these models.

3.2 Representing the React Stage

Because of the nature of the avoid stage, the models used to determine the controls and actions were segregated in terms of time and space domains. This view will hopefully enable analysts to examine the required effort versus the accuracy of predicting the avoidance of outage scenarios. For the react stage, we hoped to present a similar classification, but the react stage differs from the avoid stage because it represents the local time of the event, i.e., it models the event that has occurred once the scenario has affected the grid’s performance to be less than the optimal. Thus, there are only a certain number of control actions at the disposal of the system if they have been approved, procured, and installed before an actual event. To this end, as a guiding tool, we provide the grid's control capabilities that allow it to react to an event from the perspective of generation, transmission, and distribution infrastructure. The goal is to discuss how the responses of the react stage affect the abovementioned infrastructure and provide general guidance on their placement and procurement for improving grid performance during the event. The following information is extracted from state-of-the-art literature on power system dynamics due to small-scale and large-scale disturbances (Trudel, Bernard, and Scott 1999; Madani et al. 2010; Novosel, Begovic, and Madani 2004; Emil Hillberg 2016).

<u>Initial Degradation</u>: (< 10 seconds from performance degradation onset).

This response is dominated by the generation fleet’s inertia (governor/excitation system) as well as high-voltage direct current/AC transmission performance, static volt-ampere-reactive compensators (SVCs), and other fast-acting devices. Usually, the models for evaluating such responses are on a faster timescale and require a higher complexity of component models. To obtain a simulation in polynomial time, the complexity of the models is managed by considering smaller spatial detail, usually by aggregating the underlying transmission nodes.

<u>Mitigative Degradation</u>: (> 10 seconds from performance degradation onset).

A grid disturbance that deteriorates the system performance for more than about 10 seconds (long-term timescale) requires modeling slower-acting devices, such as manual control of power plants, mechanical dynamics of generator turbines/governors, under-load tap changing transformers, and automatic generation control. Usually, the models for evaluating such responses are on a relatively longer timescale than for the initial degradation response models. For this reason, aggregated components (network/load) based on spatial proximity information may be included in these models.

A list of example dynamics of the generation, transmission, and distribution sides that impact the react stage of the grid disturbance model are provided in Table 4. General guidance on modeling choices based on these dynamics is presented in the last column of Table 4.

Table 4. React stage model selection across generation, transmission, and distribution.

React Stage Control Impacts	Generation	Transmission	Distribution	Modeling Tools/Methods
Initial degradation	• Induction motor dynamics • Generator/excitation dynamics • Generation protective relaying • Prime mover controls	• SVCs • Flexible AC transmission system (FACTS) • Tie-line control	• Automatic switching of capacitors • DC-DC converters • Automatic on-load tap changers (OLTCs) • Grid segmentation • Feeder islanding	• Angular stability • Short-term timescale voltage stability • Individual component model details (high) • Geographical area details (low). For example: - Two-bus machine model (equal-area criterion) - Electromechanical/ electromagnetic transient simulation
Mitigative degradation	• Reserve generation dynamics (start-up/shutdown) • Power plant operator intervention • Generator change/automatic generation control (AGC) • Boiler dynamics • Generation manual control • Generator change/AGC signal	• System operator manual tie-line flows	• Manual load tap changers and distribution voltage regulators.	• Long-term voltage stability • Quasi-static steady state or slower (electromechanical) dynamic simulation • Individual component model details (low) • Geographical area details (high). For example: - Voltage collapse analysis through bifurcation theory - and/or continuation power-flow method

Based on Table 3, examples of system operators' procedures and tools for capturing dynamics relevant to the react stage of the grid disturbance are given in Appendix A.2.

3.3 Representing the Recover Stage

The recovery of the system after an outage is staged depending on how much the system has degraded. This can be characterized as the depth of the damage caused by the disturbance, which is inherently dependent on the type of disturbance. The following are the three stages captured by the recovery stage model.

- Delay – The delay in recovery efforts includes modeling the conditions and gathering resources to begin a fruitful recovery.
- Short-term recovery response – The short-term recovery response models of the initial system capabilities used to restore power are represented in the short-term response of the recover stage.
- Long-term recovery response – The long-term response of the recovery stage captures the coordinated response required to heal the system from the damages that were not restored during the short-term response.

In Table 5, the recover stage modeling choices are presented to cover generation, transmission, and distribution. The information summarized in Table 5 has been gathered after reviewing the literature (Ancona 1995; Jaech et al. 2019; Mo-Yuen Chow, Taylor, and Mo-Suk Chow 1996; Wang and Arif 2019).

Table 5. Recover stage models across generation, transmission, and distribution elements

Recover Response	Generation	Transmission	Distribution
Delay	• Assess generation assets that are online versus offline. • Select the initial source for cranking power to tripped generators – preferably, generators directly connected to bulk power systems are sorted, and if not, then isolated. Alternatively, black-start generators are used.	• Assess transmission assets that are online versus offline. • Prepare restoration pathways for the transmission system such that initial generators may be connected to the grid.	• Assess distribution grid assets that are destroyed versus not harmed. • Prepare restoration pathways for distribution grid assets necessary for the loads to be restored. • Prioritize distribution grid segments so that they can be restored in a safe sequence.

Recover Response	Generation	Transmission	Distribution
Short-Term Response	• Synchronize generators by securing restoration paths. • Turn AGCs to maintain a constant frequency. Prioritize generator excitation based on their critical restart time limits, faster response capability, proximity to the cranking source, and proximity to critical infrastructure.	• Energize tie-lines and neighboring systems that are unharmed by the outage. • Energize cleared transmission paths to load centers.	• Pick-up loads that are critical to the restoration process such as major switching stations, etc. • Restore loads with a safe ramp rate proportional to the available generators. • Deactivate tripped relays. • Restore radial lines and activate power factor-correcting equipment to avoid over voltages. • Restore distribution grid loads with no physical damage.
Long-Term Response	• Restart additional generation for adequate reserves. • Construct damaged generation assets to improve generation adequacy.	• Energize and close parallel transmission paths. • Construct damaged transmission grid infrastructure to improve transmission availability.	• Construct damaged distribution grid infrastructure to improve distribution availability.

Note that contrary to the react and avoid stages, the recover stage modeling options include procedures for re-energizing grid components. Therefore, we were not able to identify direct tools with which to model them. However, we found practices and procedures of system operators for the recover stage, which have been listed in Append A.3.

3.4 Metrics Models

The previous section presented models that can be used to represent the behavior of physical and mitigative subsystems as well as their interdependencies. This section will discuss metrics that can be used for evaluating the system performance. The philosophy of deriving system performance for the grid disturbance model was provided in (Hanif, Chalishazar, and Hammerstrom 2020). The comprehensive list of various reliability and resilience metrics used in the literature was provided in (Petit et al. 2020). Thus, we do not intend to review the abovementioned works in this section. Instead, this section aims to present a discussion on the models of metrics that can guide analysts in evaluating system performance.

Standard reliability metrics are based on the frequency and duration of outages and are backward looking, meaning they are computed based on past events. However, metrics related to resilience are forward looking. It is well understood that resilience affects reliability. In fact, increasing resilience may improve reliability, but this is not guaranteed because reliability as measured by standard metrics depends on some set of events that results in an outage, and resilience includes the avoidance of such events (Taft 2017). A key aspect of harmonizing reliability and resilience is redefining the reliability metrics from what they traditionally capture—a statistical behavior—to capturing any grid disturbance (a dynamic response). In this section, we present such models. The models are aligned with capturing system performance using the grid disturbance model, i.e., using reliability as a baseline and then predicting its trajectory across the avoid, react, and recover stages. First, we summarize the widely accepted and commonly used reliability and resilience metrics and discuss how they can be mapped into suitable grid disturbance models.

In this section, we describe how the existing reliability and resilience metrics are related and provide a road map to harmonizing them for use with the functional-form approach. The reliability metrics are well defined for distribution (e.g., the system average interruption duration index [SAIDI], the system average interruption frequency index [SAIFI], the customer average interruption duration index [CAIDI], and the momentary average interruption frequency index [MAIFI]) and for the transmission grid (e.g., N-1, loss of load probability [LOLP], and loss of load expectation [LOLE]) and are being adopted by industry to guide investment decisions. However, there is often a disconnect between the existing metrics and some of the crucial considerations for grid disturbance evaluation criterion. An example of this disconnect is as follows. The decreasing trends in the frequency and duration of power interruption (SAIDI and SAIFI) do not warrant a direct improvement in CAIDI over the collected data horizon. Thus, to acquire a more complete picture of a performance measure for the functional forms, it is important to consider a broader range of metrics and to use the existing metrics differently. Along this line, a more granular reliability analysis may also be performed to understand the trends for certain geographies, changing satisfaction criteria, and environmental conditions (Distribution Reliability Working Group. 2014). To this end, we summarize two important concepts for the selection of metrics for grid disturbance.

1. A variety of metrics could be used to depict the performance of a system using a functional-form approach. The literature on reliability metrics may be used as a starting point and/or a guiding tool for this.
2. An important point to remember for metrics modeling is that the conventional reliability metrics to be used with the functional-form approach must be applied probabilistically. This is necessary so that they can effectively demonstrate the system performance of future scenarios under alternative mitigation strategies.

Figure 6 shows an example of how the system averages for SAIDI and SAIFI can be used to acquire a more granular and complete understanding of the system performance, including the level of impact and the duration of outages. The left y-axis shows the performance measure against grid disturbances (orange line), which shows changes in the baseline system performance as the system responds to grid disturbances. On the other hand, the right y-axis shows the aspects of the reliability metrics, such as customer minutes of interruption and customers interrupted that are accumulated over time. In the graph, notice that $SAIDI_t$ and $SAIFI_t$ represent averaged customer outage duration and frequency (like SAIDI and SAIFI) but on a more granular basis. Such metrics can help capture changes in the baseline power system performance from the reliability standpoint as it experiences different events of different intensities over a period *t*. The percentage of customers online drops whenever there is an event, and the size of the step is a representation of a system's ability to avoid, react to, and recover from a given grid disturbance.

Next, we demonstrate obtaining innovative metrics to capture grid disturbance model performance. Recall the performance metric from our previous work, the system availability index (SAI) (V. Chalishazar et al. 2021). The SAI evaluated for an event is a function of the intensity and duration of the event and the system's response to the observed grid disturbance. It represents the fraction of time that a system performs its required action for a given grid disturbance. This can be represented mathematically for an event that lasts for time (T),

$$SAI = \frac{Customer\ hours\ of\ service}{Customer\ hours\ service\ demands} \quad (1)$$

Suppose that there are N customers and that an event occurs where the total time of consideration is T (time of a grid disturbance event in the avoid, react, and recover stages). If the total number of customer minutes of interruption is CMI, then SAI can be expressed as a function of $SAIDI_t$ as follows:

$$SAI = \frac{N \times T - CMI}{N \times T} = \left(1 - \frac{\frac{CMI}{N}}{T}\right) = \left(1 - \frac{SAIDI_t}{T}\right). \quad (2)$$

where $SAIDI_t$ indicates the total duration of interruption for the average customer during a predefined period and is commonly measured in customer minutes or customer hours of interruption.

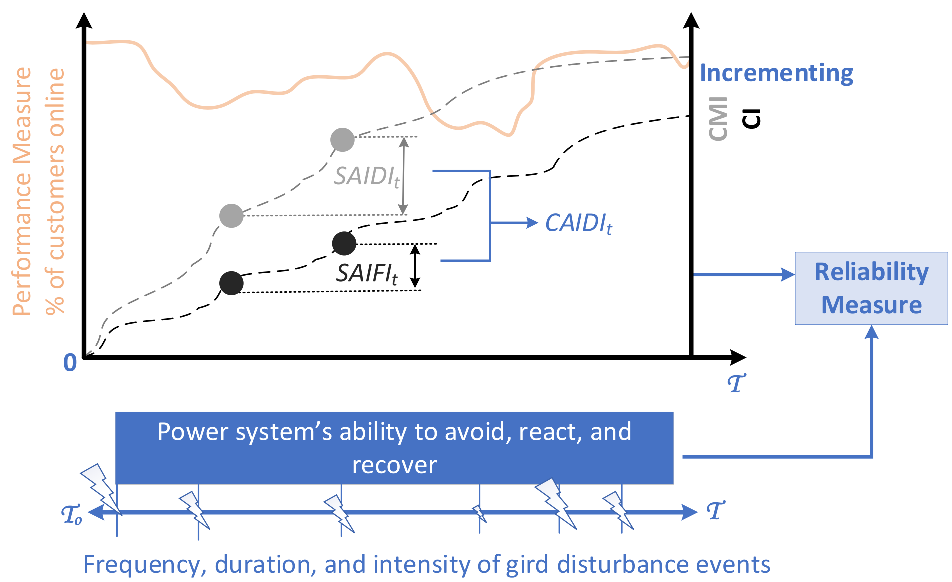

Figure 6. Metrics calculation demonstration of extending baseline reliability models to include grid disturbances.

4.0 New Mitigative Strategies

The previous sections discussed grid disturbance model selection based on the analysis requirements and underlying physical and mitigative subsystems. This section extends the discussion to new mitigative subsystems, where an example of a TES is provided. Section 4.1 offers a generic TES model that is based on value-based operation of the system, e.g., a design to extract the required response by discovering a price signal and coordinating the battery energy storage system. Section 4.2 maps such value-based operation to the favorable qualities of the system for mitigating grid disturbances. Section 4.3 shows the relevance of the generic TES model to the state-of-the-art TES implementation for selected grid mitigation scenarios and how they may address all grid disturbance stages. Finally, a comparison between a conventional demand-response (DR) scheme and an example of a TES implementation is provided to demonstrate an assessment of potential new mitigative strategies for grid disturbances.

4.1 Generic Transactive Energy System Model

We start with presenting a generic methodology of how a TES systematically introduces distributed intelligence to the system. These concepts are adopted from the TES valuation principles provided by (Hammerstrom et al. 2016). Figure 7 shows the three main components of a TES design, which are as follows:

- Objective: The goal of the system.
- Incentive: Translation of the objective into a monetary/non-monetary signal to help change the system (underlying components) behavior.
- Response: Actions to address the objective, encouraged by the incentives.

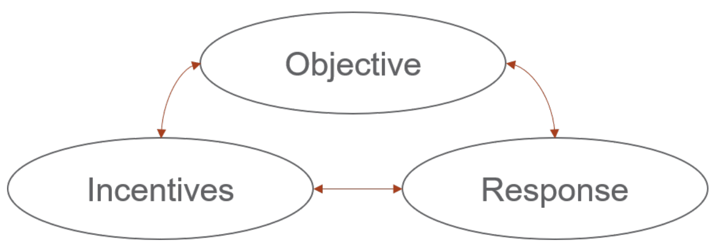

Figure 7. A TES generic operational model.

Therefore, the TE design facilitates *incentives* for the aimed *objective* and extracts the respective *responses*. Identifying a unique functional form that uses relationships between objectives, incentives, and responses to explain the TES behavior is a difficult task, especially because the TESs are usually designed to cater to general objectives such as “market efficiency” or “economic competency.” This is because there may be implicit actions (responses) that might affect objectives not as a primary response, but rather as one of the byproducts facilitated through the TE design. For example, the Pacific Northwest Smart Grid Demonstration (PNWSGD) (Hammerstrom et al. 2015) showed that market signals can be used to effectively mitigate congestion in certain circuits. In principle, congestion causes the market prices to increase, when relatively expensive DERs win the rights to locally supply load and therefore mitigate congestion. One may wonder whether the price increase (incentive) explicitly raised the DER participation level (response) and was intended to reduce congestion (objective). However, reducing congestion was not the main goal of this TES framework but was part of the overall design to gather distributed responses to external conditions. Therefore, a TES is the framework (a market design in this case) that facilitates such a price increase to signal "not-normal" grid conditions (e.g., congestion) and thus triggers a response to alleviate that condition.

For the case of grid disturbance, the TES should be designed to avoid, react to, and recover from a grid disturbance event. Using TES designs to improve resilience has been explored in (The GridWise®Architecture Council 2020). A TES can

- Facilitate the local system objectives necessary to achieve grid disturbance goals.
- Design the incentive signals necessary for obtaining the required response.
- Extract meaningful system responses to the incentive signals.

4.2 Transactive Energy System Design Parameters

The functions of the TES components—objective, incentives, and responses—must be connected to the desired TES qualities identified in the previous section. Table 6 connects some identified qualities of TESs that affect grid disturbances with the main TES functionalities to provide an example of how TES design may be carried out. Some example design criteria for individual TES components are discussed to achieve the desired TE quality.

Table 6. TE design parameters exploration for the desired quality related to grid disturbance.

TE Qualities[1]	Objectives for Extracting Required Quality	Basis for Incentive Signal Design	Technologies to Provide Response Toward Achieving Quality
Actor motivation	Minimize the cost of outages and maximize the benefit to proactively support grid disturbances	Avoided cost of infrastructure loss, loss of savings for building owners and asset owners, deferred costs of transmission and distribution equipment, equipment replacement costs burden, maintenance expenses burden, operating expenses, cost of customer inconvenience and loss of productivity	Building automation system, DERs, industrial control systems, bulk generation
Contracted response	Maximize the procurement of economic, autonomous energy and supporting ancillary services response capabilities	Loss of revenue for highly responsive generators in the wholesale market, high reserve price, loss of noncompetitive response contracts through bilateral trades	Building automation system, DERs (inverter control), industrial control systems, bulk generation

[1]Interested readers are referred to (Hanif, Chalishazar, and Hammerstrom 2020) for more information on the identified TE qualities for positively influencing grid disturbances.

TE Qualities[1]	Objectives for Extracting Required Quality	Basis for Incentive Signal Design	Technologies to Provide Response Toward Achieving Quality
Forecast time horizon	Improve forecasting time horizon for critical states/components and events that may trigger the onset of a scenario and react to and recover from the event	Loss of revenue in day-ahead and real-time market due to lack of foresight of internal and external conditions, flexibility potential, deferred cost, revenue lost due to local DER planning	Energy management system, DERs (metered), SCADA, utility planning tools, advanced metering
Locational granularity	Maximize locational granularity to spread out the mitigation strategy for critical states/components	Avoided loss of infrastructure and widespread outage and loss of load, revenue lost due to local DER flexibility, loss of granular bilateral and market trading	Energy management system, DERs (communication system), SCADA, utility planning tools, advanced metering
Nature of DER control	Maximize DER diversity and control capabilities	Avoided loss of revenue related to not participating in competing diverse market products, avoided loss of revenue in bilateral trades	Building automation system, DERs (inverter control), industrial control systems, bulk generation
Prosumer incentive	Minimize the cost of loss of load outages and maximize the benefit to proactively support grid disturbances using prosumer flexibility	Avoided cost of infrastructure loss, loss of savings for building owners and asset owners about net load management, deferred costs of transmission and distribution equipment, equipment replacement cost burdens, maintenance expenses burden, operating expenses, cost of customer inconvenience	Building (residential) automation system, DERs
Supplier incentive	Minimize the cost of generation outages and maximize the benefit to proactively support grid disturbances using higher supply-side resources	Avoided cost of infrastructure loss, loss of savings for generators to be able to not participate in energy and ancillary service markets, deferred costs of transmission and distribution equipment, equipment replacement cost burdens, maintenance expenses burden, operating expenses	Bulk generation, DERs (supply-side)
Time interval granularity	Minimize decision-making algorithm's time resolution to encourage vulnerable state changes	Avoided opportunity cost for responding to faster controls (regulation type signals), avoided cost of infrastructure lost due to not being able to respond to fast disturbance propagation, avoided cost of not participating in faster timescale market products	Energy management system, DERs (communication system), SCADA, utility simulation tools, advanced metering
Transacted commodity	Minimize out-of-market transactions and maximize market transacted quantity	Loss of revenue for higher-performing assets due to non-competitiveness, loss in revenue for non-participating assets, reduction in	Building automation system, DERs (inverter control), industrial control

TE Qualities[1]	Objectives for Extracting Required Quality	Basis for Incentive Signal Design	Technologies to Provide Response Toward Achieving Quality
		economically procured highly responsive assets, avoided loss of revenue of demand-side earnings from bid	systems, bulk generation

Table 7 provides an example of how the objective, incentive signals, and available technology may be utilized to achieve a certain TE quality that is favorable for grid disturbance mitigation. Incentive signals are a product of the incentive mechanism design, which inputs the required data, limitations, and capabilities of the technologies, and enrolled participant's willingness to participate. Table 7 provides some examples of such incentive mechanisms, i.e., transaction platforms, which may help in organizing the TES objectives and staging the required system response. The interested readers are referred to Hammerstrom et al. (2016) for additional examples of incentive mechanisms.

Table 7. Examples of incentive mechanisms.

Incentive Mechanism	Definition	Favorable Temporal Resolution	Favorable Spatial Resolution	Example of Demonstrated TE Systems
Bilateral transactions	Form of wholesale energy purchase/sell that does not require auction markets. The seller's and transporter's costs are paid by the purchaser and used to make decisions.	Spot markets, forward markets (month/day/hour ahead).	Retail markets, wholesale market, single entity negotiations.	TeMix (Cazalet 2010)
Double-auction market	The energy price is determined by a market clearing method that consists of supply offers and demand bids from the producers and consumers, respectively.	Spot markets, forward market (day/hour ahead).	Wholesale markets.	AEP GridSMART (Widergren et al. 2014), GridWise Olympic Peninsula (Hammerstrom et al. 2008)
Nodal cost formulation	Computational agent represents a contiguous portion of the grid and is responsible for economically balancing the energy it imports/exports locally.	Integration with spot market, forward market (day/hour ahead).	Retail market, wholesale market, iterative market.	PNWSGD (Hammerstrom et al. 2015)

In Table 7, the incentive mechanisms' temporal and spatial resolutions are shown to provide an idea of the implementable length and scale of each incentive mechanism. For example, bilateral transactions have been shown to transact bulk energy over a long-time horizon. They are used to hedge the uncertainty associated with real-time price dynamics. Therefore, they do not provide an opportunity to extract a response in real-time for changing grid conditions. Under these circumstances, the bilateral transactions may not be suitable for providing a real-time response based on grid degradation in the react and recover stages of a grid disturbance. However, bilateral transactions may be used to procure the capacity to be available for grid disturbance stages. Similarly, the suitability of double-auction market and nodal cost formulation to provide support during grid disturbance phases of reacting and recovery may be evaluated using the models identified in Section 3.0.

4.3 Example Transactive Energy System Implementation for Grid Disturbance Mitigation

This section provides an example of state-of-the-art TES implementation for mitigating grid disturbances.

4.3.1 Transactive Energy System-Enabled Distributed Black-Start

This method deals with the applicability of black-start using TESs (Bhattarai et al. 2021). Figure 8 shows an overview of the proposed method.

First, we present the relevance of this method concerning the generic TES model of Section 4.1.

- Objective: To provide black-start, the objective of a TES is to procure cost-effective distributed resources as follows:
  - Position a system such that the system has enough resources both in terms of type and quantity to black-start the system.
  - The TE mechanism should facilitate the procurement of necessary black-start-capable resources and other resources.
- Incentive: As the method sets up a TES market, a price is discovered that promotes distributed resource engagement as follows:
  - The incentive for a distributed black-start is a price signal obtained by setting up a double-auction market.
  - The incentives respond to resource availability and resources’ proven ability to perform.
- Response: The response is a sequence of operations guided by the objective and incentives.
  - Engage appropriate mix and sequence of black-start and other non-black-start generation resources.
  - Dispatch loads via proper dispatch of market participants.
  - Energize additional loads via dispatch of switching commands.

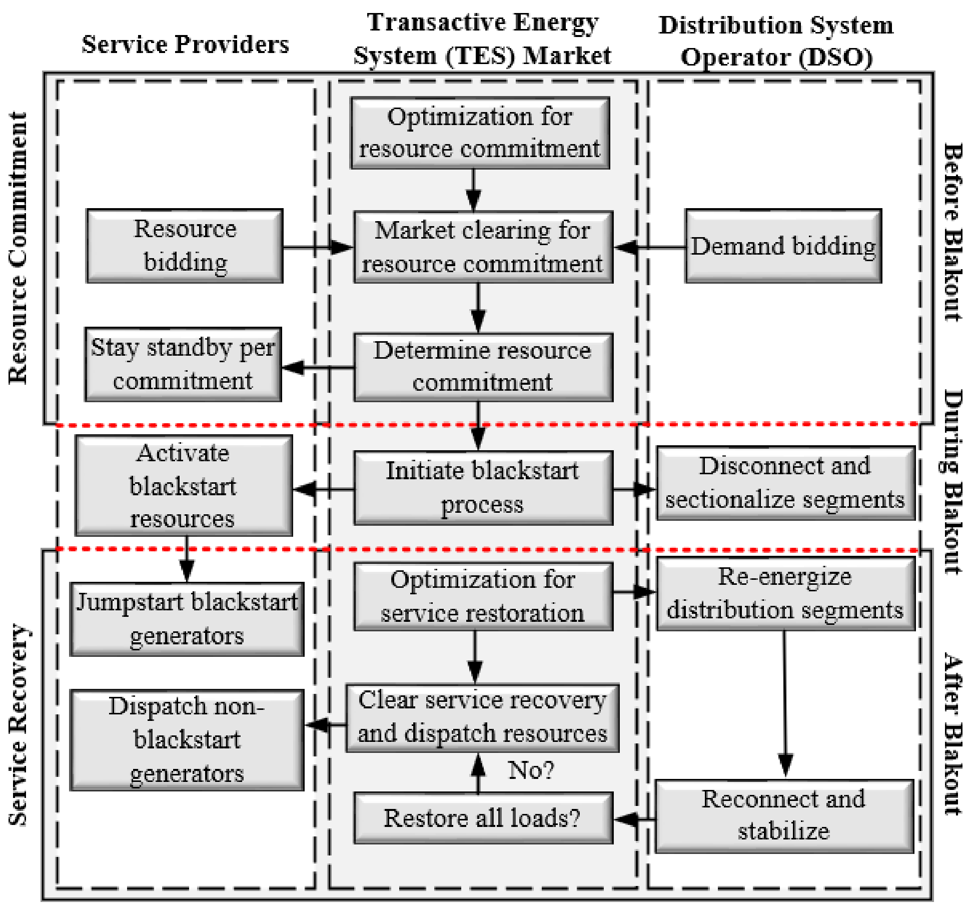

Figure 8. Overview of distributed black-start using a TES (taken from (Bhattarai et al. 2021))

Second, we demonstrate how this TES example, as a new mitigative subsystem, affects the grid disturbance model. The chosen example is clearly tailored toward black-start operation, which is related to the recover stage of the grid disturbance model. Therefore, only the impact to the recover stage of the grid disturbance model is provided.

<u>Impact of Distributed Black-start on the Recover Stage of the Grid Disturbance Model:</u> This is the grid disturbance stage after the blackout event. The TES market implements novel features to improve upon the conventional service recovery process and therefore should improve the recovery time of the grid disturbance model. In contrast to the conventional restoration process, where the re-energizing paths are usually fixed, the TES method runs an optimization for service restoration and allocation of additional resources to satisfy all loads. This feature allows for dynamic energizing/re-energizing options based on where the resources are available. Moreover, the dynamic nature of a TES market allows flexible demand-side resources to coordinate with other conventional resources (e.g., non-black-start committed generators, dynamic switches, etc.), if available to restore all loads. This not only improves the efficiency of load restoration (recovery time), but also improves the availability of existing resources.

Third, we present a qualitative comparison between (1) a conventional DR scheme and (2) the distributed TES black-start application.

For a fair comparison, we do not include supply-side resource participation in the distributed TES black-start application. Similarly, for both mitigations, the objective is to increase the rate of recovery of infrastructure after a blackout event when the grid is in the recover stage. Because there are many forms of a DR scheme, we use a simple mechanism. It is assumed that the operator has contracted DR participants to reserve their energy to be available during the recover stage of the grid disturbance. The operator then utilizes this energy in the grid as appropriate to support recover actions. One form of utilization is to shift energy consumption from high loading areas to low loading areas. It is assumed that the participating demand-side resources are paid in advance for reserving the capacity. The contracted resources are assumed to not be purchased competitively because there are no examples of DR scheme contracts for grid disturbance mitigation. The wholesale markets accepting demand bids are aimed at improving the social welfare of the system, not mitigating technical concerns. Similarly, we do not consider that any penalty is present based on the performance of these resources. Once the operator is notified that conditions are safe, it sends signals to the participants, arranged in the order of their priority to support grid recovery. Therefore, we assume a very simple, yet representative conventional DR scheme for supporting grid recovery processes.

To compare these two new mitigative subsystems, performance is discussed against two categories: (1) technical performance and (2) economic performance.[1] Technical performance is discussed using the total area under the system degradation curve from a disturbance. For the recover stage, this amounts to the rate of change of state improvement (e.g., percentage load recovered per minute). Economic performance is discussed using cost as a metric, as in we present a qualitative comparison of cost (in $s) to implement such a new mitigative subsystem and its comparison to existing costs.

[1] Consideration of economics is important. Theoretically, it may be possible to procure infinite demand-side resources. However, the cost of implementing such a demand-response scheme is not practical.

Table 8. Technical comparison of two mitigative subsystems to recover from a grid disturbance.

Comparison	DR Scheme	TES (Distributed Black-Start)
Percentage load recovered per minute	• Potential to recover time of all loads by allowing their power to shift during that time, i.e., to shift their load to a different time of use. • Plans to prioritize demand shifting are static, i.e., no feedback loop with the system conditions, which may result in under/over utilization of resources.	• Potential to improve recovery time of all loads by engaging demand-side resources to participate in a load shifting mechanism, where their individual preferences are traded against system conditions. • Dynamic demand shifting, which adjusts the demand pattern based on spatial and temporal requirements of grid recovery, helps optimize resource utilization.
Cost of operation	• Increase in cost due to payments to contracted demand-side resources to reserve and shift their load. • Cost reduction due to the avoided cost of long delays in recovering power to the grid and avoiding the possibility of utilizing expensive generators to secure the grid.	• Extra cost will be incurred in setting up a market for enabling dynamic demand-side participation to support grid recovery, because most of the existing infrastructure does not support such platforms, at least at scale. • Incentive signals to drive demand-side resource participation for grid recovery will be dependent on the system conditions. Therefore, the costs related to the payments to demand-side resources are dependent on the requirement of demand-side resources participating in the grid recovery stage. • Potential for significant societal savings by allowing the grid to recover much faster than through static demand-side resource participation, which is also based on a user's willingness to shift load.

With respect to grid disturbance mitigation, there is another targeted TES example that caters to emergency power allocation (McDermott et al. 2021). For completeness, a discussion of "Power Rationing using TES" and how it affects the grid disturbance model's react stage is provided in Appendix A.

5.0 Conclusion

This report proposed an evaluation model for grid disturbances that uses a parameter-based functional-form modeling approach. The backbone of the evaluation model is the grid disturbance theory, which harmonizes reliability and resilience and promotes the utilization of a common metric over time as a performance indicator—for example, the area under the curve of percentage customers online before, during, and after the grid disturbance. In this way, the evaluation model can objectively quantify grid performance during disturbances. To utilize this objective quantification capability of the grid disturbance concept, evaluation mechanism of current and existing mitigative actions were also explored in this report.

The evaluation model discussed in this report presented physical and mitigative subsystems as main components to be captured for parameterizing system performance against disturbances. Physical subsystems were shown to be generalizable with respect to their placement in the grid, i.e., the distribution, transmission, and generation parts of the grid. For characterizing mitigative subsystems, a contingency selection process was described where the system parameters were identified using the concept of corresponding physical subsystems violating thresholds and exceeding predefined margins. To show the relevance of this generalization to the current grid practices, we showed how models from the power grid literature can be utilized. We provided a detailed discussion on how the reliability and resilience metrics could be harmonized and used within the proposed grid disturbance evaluation model. This harmonization is important because a common metric provides a fair valuation of each novel mitigation. Specifically, it allows system analysts to quantify the effect of any newly proposed mitigative subsystems (e.g., a TES) against system abilities to address the avoid, react, and recover stages.

As an example of a new mitigation strategy, a TES mitigation was presented and compared to an existing mitigation strategy—conventional DR. In doing so, we compared various qualities of the mitigative strategies with grid disturbance performance. We hope that the proposed evaluation model can guide an analyst when valuing future novel mitigation strategies.

For future works, we plan to use the proposed evaluation model for the following activities.

- To adopt, select, and modify existing power grid models to capture the grid disturbance stages of avoid, react, and recover for a sizable disturbance event (e.g., Texas' winter blackout of 2021).
- To modify existing and design new mitigation strategies.
- To quantify improvements in grid disturbance performance due to the implementation of mitigation strategies.
- To automate the disturbance analysis from the perspective of setting up the experiment until metric post-processing.

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Appendix A – Industry Standard Practices, Methods, and Tools Relevant to Grid Disturbance Models

A.1 Independent System Operator Example Models for the Avoid Stage

Table 9. Avoidance models' independent system operator (ISO) examples across time dimensions.[1]

Scenario Onset Modeling	Low-Granularity/Short-Horizon	Low-Granularity/ Long-Horizon	High-Granularity/ Short-Horizon	High-Granularity/ Long-Horizon
Probabilistic Scenarios Onset	• Reserve Procurement (Scarcity)/Ancillary Services	• Summer Load Assessment – Unserved Capacity Margin (UCM) • Resource Adequacy – Loss of Load Expectation (LOLE) • Long-term Load and Renewable Forecast Errors on Planning (1-in-x years)	• Short-term Load and Renewable Forecast Errors on Operations – Mean Absolute Percentage Error (MAPE)	• N/A
Stressor-Initiated Scenarios Onset	• Operations Planning: Real-Time Dynamic Security	• N/A	• Area Control Error (ACE) Monitoring • Real-Time Contingency Analysis (RTCA) • Operations Planning: Real-Time Voltage Stability Assessment (RT-VSA)	• Contingency Analysis Model

[1] Note that some of the procedures/models adopted by ISOs are represented by the calculation of the metric itself, e.g., LOLE and MAPE. This is done to provide reference for the reader on what the ultimate calculations yield. Section 2.3 details information about metrics calculation and its relationship to performance measure.

Scenario Onset Modeling	Low-Granularity/Short-Horizon	Low-Granularity/ Long-Horizon	High-Granularity/ Short-Horizon	High-Granularity/ Long-Horizon
Functionally Tracked Scenario Onset Probabilistic Scenarios Onset	• N/A	• Transmission Planning (Limits on Megawatt Flow on Major Lines, Generation MW) • Day-Ahead Market	• Real-Time Market	• Maintenance Outage Model

Table 10. Avoidance models' ISO examples across space dimensions.

Scenario Onset Modeling	High Aggregation / Small Scale	Low Aggregation / Small Scale	High Aggregation / Large Scale	Low Abstract / Small Scale
Probabilistic Scenarios Onset	• Reserve Procurement/ Ancillary Services • Summer Load Assessment • Resource Adequacy	• N/A	• Local Forecast Errors in Planning	• System-Wide Forecast Errors in Operations
Stressor-Initiated Scenarios Onset	• N/A	• ACE monitoring	• N/A	• Real-Time Contingency Analysis (RTCA) • Operations Planning • Real-Time Voltage Stability Assessment (RT-VSA) • Real-Time Dynamic Security Assessment (RT-DSA)
Functionally Tracked Scenario Onset	• N/A	• Day-Ahead Market • Transmission Planning	• N/A	• Real-Time Market

A.2 Independent System Operator Example Models for the React Stage

In general, there are four main procedures designed to develop a model for the react stage of a grid disturbance.

1. <u>Exceptional dispatch (ED) of resources</u>**.** During emergency operations, or when the ISO is unable to maintain its system reliability by using resources, the ISO may authorize ED for energy transactions. This may include forced shutdowns or forced start-ups of generation,

participating load, and transfers. ED can be committed during various system conditions as stated below.

– System emergency, which may affect reliability.
– Times when a portion of generator production is reduced due to being shut down either due to testing or maintenance/overhaul.
– Overgeneration during high-renewables time periods.
– Voltage abnormalities (under/over-voltages).
– Market clearing failures.

2. Contingency dispatch. During contingencies that are greater than or equal to 80 percent of the severity level of the single most severe contingencies, CAISO can dispatch contingency reserves and return ACE values to a nominal pre-disturbance range within 15 minutes of the event.
3. Load shedding or demand response. ISOs can call for demand response resources to reduce load for certain intervals during contingencies or generation insufficiencies to maintain the reserve margins until the threat has passed. If the demand response is not available for activation within the time frame required for maintaining system stability, ISOs can authorize controlled rolling blackouts/load-shedding events to prevent any chance of cascading outages.
4. Public safety power shutdown. During wildfire season and based on weather conditions, utilities preemptively disconnect transmission lines that pose a high risk of starting a wildfire. Under such conditions, customers may lose power for several hours.

Given these four procedures and the model selection guidance, Table 11 places relevant models by system operators to capture the react stage of the grid disturbance across generation, transmission, and distribution.

Table 11. React stage example for react stage models from system operator models.

React Stage Control Impacts	Generation	Transmission	Distribution
Initial Degradation	• Automatic generation control • Regulation • Real-time market dispatch	• Congestion mitigation • Transfer optimization	Distribution ride-through controls, disconnect
Mitigative Degradation	• Contingency dispatch • Exceptional dispatch	• Public safety power shutdown	• Load shedding or demand response

A.3 Independent System Operator Example Models for the Recover Stage

ISOs and reliability coordinators have a system restoration plan. The short- and long-term responses from the ISO perspective are to bring sections of the grid back online and synchronize them with the main grid. ISOs do not have any market mechanisms for the recover stage, but real-time system operators are trained to manage system restoration and recovery strategies. The reliability coordinator is responsible for taking over control of the grid during a black-start restoration process, and strict procedures and plans are designed ahead of time. As an example, CAISO has an operational procedure #RC0460,[1] which was developed to establish the protocols that will be implemented to coordinate system restoration activities after a major system disturbance. To develop functional forms from the ISO perspective, it may be a good idea to look at developing simulation scenarios for the restoration of the grid based on various system conditions. Data from historical events and restoration times can be used as references to validate the functional forms. Historical data on blackouts, customer and load outages, and restoration times are available in the Electric Disturbance Events (OE-417) Annual Summaries.[2]

A.4 Emergency Power Allocation (Rationing) Using the Transactive Energy System Method

Another example of a transactive energy system designed to handle grid disturbance is the method of power rationing (McDermott et al. 2021). The main transactive energy system components of this method are as follows.

- Objective:
  - Equitably distribute power during periods when there is not enough power to go around.
  - Provide the means for individual participant preferences to achieve higher levels of economic efficiency than would otherwise be possible.
- Incentive:
  - Provide basic, essential electricity that is endowed to participants during rationing events at a low price.[3]
- Response:
  - The information in the price signal is expected to dictate the maximum power for the market period, and the assumed home EMS will adjust the load to conform to the required power.
  - The system-required power may be higher or lower than the initial endowment but will better conform to the expressed preferences and thereby achieve greater economic efficiency during a power-rationing event.

[1] https://www.caiso.com/Documents/RC0460.pdf
[2] https://www.oe.netl.doe.gov/OE417_annual_summary.aspx
[3] The incentive for this system is not fully defined yet.

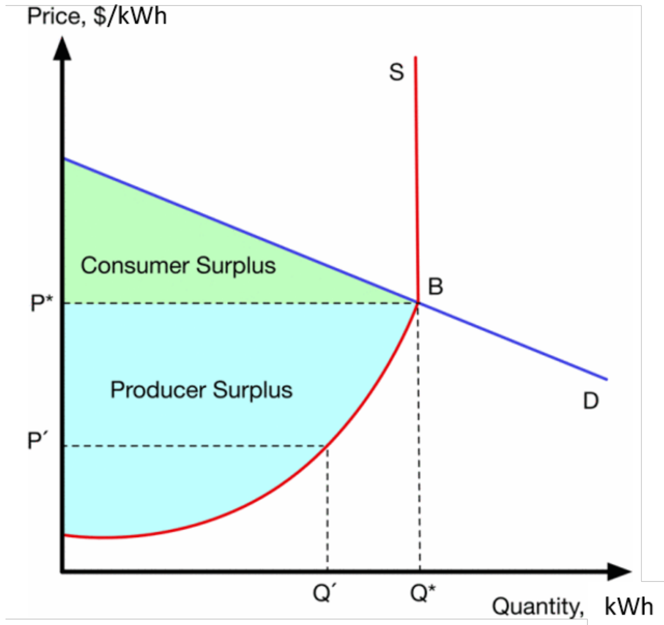

Figure 9. Ration market operation (from McDermott et al. 2021).

The main principle of the proposed rationing market by McDermott et al. (2021) is shown in Figure 9.. In the figure, the outage-limited supply curve (S), demand curve (D), economically efficient market clearing point (P* and Q*), and rationed allocation (P' and Q') can be seen for the demand exceeding the supply scenario. A double-auction market satisfies the demand above and beyond the ration allocations.

As the current implementation of this TES example caters to the real-time balance of demand and supply, its relevance to the react stage of the grid disturbance model is discussed below.

<u>React:</u> This is the grid disturbance stage during the emergency condition, i.e., a scarcity of generation and/or transmission event. TES power rationing improves the time the system takes to react to the disturbance. This is because when using this method, the operator can prioritize the available response to target the vulnerable portions of the grid. This can help isolate fault areas such that the blackout does not propagate through the system, which avoids cascaded blackouts. For example, in the case of extremely high winds, transmission lines may get disconnected and limit large generator support to certain grids areas. Allowing users to stay connected to the grid, although with limited powers that they agree upon, can help the operator avoid involuntary load shedding and cascaded blackout scenarios. Therefore, this TES example limits the disturbance propagation and even improves the final settled degraded system state.

Like Section 4.3.1, comparison of the TES power-rationing example with other mitigation strategies, such as the conventional demand-response scheme, may be carried out but is not presented in this report. It is our hope that conclusions like the TES distributed black-start capability may be obtained through such a comparison but directed toward the react stage.

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